Earnings Release
Q3 26

Pampa Energía, an independent energy company with active participation in the Argentine oil, gas and electricity, announces the results for the nine-month period and quarter ended on September 30, 2026.

Buenos Aires, November 2, 2026

Stock information

Buenos Aires Stock Exchange
Ticker: PAMP

New York Stock Exchange
Ticker: PAM
1 ADS = 25 common shares

Share capital as of October 30, 2026
1,343.6 million common shares/ 53.7 million ADS

Market capitalization
AR$6.5 trillion/US$3.90 billion

Information about the videoconference

Date and time
Tuesday, November 3
10 AM Eastern Standard Time
12 PM Buenos Aires Time

Access link
bit.ly/Pampa3Q2026VC

For further information about Pampa

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Argentina's Securities and Exchange Commission
www.argentina.gob.ar/cnv

US Securities and Exchange Commission
sec.gov

Basis of presentation

Pampa reports its financial information in US$, its functional currency. For local currency equivalents, transactional FX is applied. However, Transener and TGS's figures are adjusted for inflation as of September 30, 2026, and converted to US$ using the period-end FX rate. Prior quarter´s figures remain unchanged as reported.

Q3 26 main results[1]

Sales reached US$790 million in Q3 26[2], up 34% year-on-year, mainly driven by the normalization of the WEM, which supported higher spot energy prices and B2B sales, increased gas sales to our CCGTs, growing crude oil sales and stronger Reformer prices. These effects were partially offset by lower gas deliveries under Plan Gas GSA and to industrial customers, as well as the impact of crude oil hedges.

Thermal power generation margins stood out during Q3 26, supported by their efficiency and vertical integration with our gas upstream business.

Pampa's main operational KPIs		Q3 26	Q3 25	Variation
Oil and gas	Production (kboe/day)	99.7	99.5	**+0%**
	Gas production (kboepd)	*77.6*	*82.2*	**-6%**
	Crude oil production (kbpd)	*22.1*	*17.3*	**+28%**
	Average gas price (US$/MBTU)	5.0	4.4	**+12%**
	Average oil price (US$/bbl)*	55.7	61.1	**-9%**
Power	Generation (GWh)	5,315	5,421	**-2%**
	Gross margin (US$/MWh)	35.0	26.5	**+32%**
Petrochemicals	Volume sold (k ton)	115	122	**-6%**
	Average price (US$/ton)	1,309	937	**+40%**

Note: * Realized price, net of hedge, export duty and quality/logistic discounts.

Adjusted EBITDA[3] totaled US$398 million, up 23% year-on-year, reflecting higher thermal generation margins in the spot and B2B markets, together with the benefits of vertical integration between gas production and thermal power generation, offset by the impact on crude oil hedges.

Net income attributable to shareholders reached US$129 million, 6 times Q3 25, mainly driven by lower deferred income tax expense and improved operating margins, partially offset by lower FX gains.

Net debt stood at US$1.731 billion as of September 2026, vs. US$1.319 billion as of June 2026, reflecting higher capital expenditures, mainly at FEPASA, equity contributions to affiliates under development, prepayments related to the GPM expansion, and collateral posted for crude oil hedging, partially offset by operating cash flow generation and dividends received from Transener.

1 The information is based on FS prepared according to IFRS in force in Argentina.

2 Sales from the affiliates CTBSA, Transener and TGS are excluded, shown as 'Results for participation in joint businesses and associates.'

3 Consolidated adjusted EBITDA represents the flows before financial items, income tax, depreciations and amortizations, extraordinary and non-cash income and expense, equity income, and includes affiliates' EBITDA at our ownership.

1. Relevant events

1.1 Urea project: approval under RIGI

On September 7, 2026, the MECON approved the Fertilizer Project's application to join the RIGI under the PEELP category (Res. No. 1468/26). Announced on July 17, 2026, the project involves the construction, operation and management of an industrial complex with an annual production capacity of 2.1 million tons of granular urea. The estimated investment totals approximately US$2.7 billion, under a lump-sum turnkey contract, with operations expected to begin by year-end 2029.

This milestone marks Pampa's entry into the fertilizer business, expanding its presence into a sector that plays a key role in agricultural productivity and global food security. The project is also aligned with Pampa's strategy of monetizing its Vaca Muerta shale gas reserves through new high-value-added businesses, while further strengthening its vertical integration and industrial footprint.

1.2 Gas transportation capacity awarded

On August 26, 2026, the remaining transportation capacity under the second stage of the tender for the expansion of the GPM and final tranches was awarded. Pampa and its subsidiaries secured 1.4 mcmpd in the Bahía Blanca tranche and 0.7 mcmpd of capacity to the Buenos Aires metro area, on top of the 3.2 mcmpd awarded in April 2026. Awarded shippers executed ship-or-pay transportation agreements for terms of up to 35 years, effective May 2027.

Subsequently, on October 8, 2026, following the oversubscription of bids for transportation capacity to Bahía Blanca, TGS requested authorization from the SE to expand the GPM by an additional 4.5 mcmpd, within the 6 mcmpd expansion capacity authorized by ENARSA. Once approved, TGS will award Pampa an additional 4.3 mcmpd of transportation capacity to Bahía Blanca.

Separately, on September 4, 2026, TGN launched an open season to contract the remaining firm gas transportation capacity from the Buenos Aires metro area to the Litoral and Center regions, and Salta. Pampa and its subsidiaries submitted bids for 0.96 mcmpd on the Buenos Aires metro area – Salta tranche, under a 35-year agreement. As of today, the award remains pending.

The 9.6 mcmpd of transportation capacity awarded under the GPM expansions, together with 2.5 mcmpd previously contracted and 3.5 mcmpd of gas consumed at the wellhead by CTLL, bringing a total of 15.6 mcmpd. This expanded capacity is key to strengthening the vertical integration of our E&P business with the natural gas requirements of our thermal power plants and future urea facility. It will also create opportunities to market gas at competitive prices in the Buenos Aires metro area, secure firm exports to northern Chile and Brazil, and enhance margins in our power generation business. Specifically, under the framework established by Res. SE No. 400/25, electricity generated using natural gas transported through new infrastructure, or at new generation units built after January 1, 2025, captures the full dispatch margin in the spot market (FRA=1).

1.3 Power generation

Amendments to the WEM guidelines – Res. SE No. 400/25

On October 21, 2026, the SE amended the guidelines set under Res. No. 400/25, mainly regarding CVP declarations by power generators and energy trading conditions in the MATE B2B PPA market, among other changes (Res. SE No. 293/26).

For generators managing their own fuel supply, the amendments introduced limits on declared CVP relative to the reference CVP published by CAMMESA. During 2027, the CVP declaration range will be set between 50% and 117.5% of the reference CVP, while from 2028 onward, to between 25% and 110%. For the remainder of 2026, the existing range of 75% and 125% will remain in effect. Generators using fuel

supplied by CAMMESA under the "Gas Acuerdo" scheme must declare a CVP of up to 100% of the reference value.

The amendments also eased energy trading restrictions under the MATE for thermal generation commissioned before 2025. These generators may contract with large WEM users and large users of distribution companies (GUDIs) for volumes of up to 20% of their actual monthly generation through March 2027, 60% between April 2027 and March 2028, and 80% between April and December 2028. From January 2029 onward, they will be allowed to trade energy without restrictions on volumes or type of demand, bringing full liberalization forward by one year compared with the original schedule established under Res. SE No. 400/25.

Extra-Trend Demand Regime (XDEM)

On September 25, 2026, the SE established the regulatory framework for the Extra-Trend Demand (XDEM) regime in the WEM, applicable to new demand or expansions of existing demand representing at least 0.5% of the WEM's average demand over the last rolling 12 months. The regime establishes two categories: XDEM Production, covering all types of consumption, and XDEM Data, specifically for data centers and artificial intelligence infrastructure.

To participate in the WEM, XDEM applicants must submit a supply plan detailing their expected demand, demonstrate backup arrangements ensuring contractual coverage of at least 80% of their energy requirements, and secure take-or-pay capacity backup equivalent to 100% of maximum demand for XDEM Production and 115% for XDEM Data. In this context, Pampa's participation in the expansion of firm transportation capacity on the GPM could enable CTGEBA, which operates on natural gas, to qualify as new eligible supply for XDEM demand.

End of HINISA's concession

On July 31, 2026, HINISA's assets were transferred back to Hidroelectricidad Mendocina S.A., a company owned by the Province of Mendoza. Said company will operate the assets until its shareholding is awarded to a new owner or, at the latest, until December 31, 2026.

Previously, on July 28, 2026, the National Government, together with the Province of Mendoza, launched a national and international public tender for the concession of electricity generation and the sale of the shareholding in Hidroelectricidad Mendocina S.A. (PEN Decree No. 667/26).

Update to the regulated remuneration scheme

On October 8, 2026, the SE granted an 11% increase to the regulated remuneration of electricity generation not covered by Res. No. 400/25, including, among others, HIDISA and HPPL. The increase became effective in October 2026 (Res. SE No. 281/26).

1.4 Oil and gas

Natural gas purchase tenders at MEGSA

In October 2026, Pampa held gas purchase tenders through MEGSA, securing 6 mcmpd of natural gas from the Neuquina Basin, sourced from oil-producing blocks. The awarded volumes were allocated across three contracts: **(i)** 1 mcmpd from May 2028 to April 2033; **(ii)** 3 mcmpd from May 2029 to April 2034; and **(iii)** 2 mcmpd from May 2030 to April 2035. All volumes were awarded at a price of US$2.25 per MBTU at the transportation system manifold (PIST).

Pampa expects the growth in unconventional oil (shale oil) production to increase the availability of associated gas, which benefits from a very low production cost. However, these volumes alone are unlikely to meet domestic gas demand, making shale gas development necessary to ensure supply.

Against this backdrop, Pampa seeks to capitalize on procurement opportunities at prices below the marginal cost of developing shale dry gas. This strategy allows the Company to optimize its gas supply portfolio while preserving the value of Pampa's production and ensuring that the development of our most competitive fields remains economically attractive.

Natural gas export quota allocations

The SE allocated Pampa the following firm gas export quotas for the 2027-2028 period, with volumes differentiated by demand seasonality:

In mcmpd	2027	2028
Summer (Jan-Apr and Oct-Dec)	0.56	0.78
Winter (May-Sep)	0.49	0.57

1.5 Transener and TGS

Tariff updates

Applicable as of:	Transener/Transba		TGS	
	Increase	Resolution	Increase	Resolution
July 2026	2.4%	ENREGE No. 176 and 180/26	2.6%	ENREGE No. 161/26
August 2026	1.4%	ENREGE No. 338 and 340/26	1.7%	ENREGE No. 356/26
September 2026	1.2%	ENREGE No. 507 and 509/26	1.7%	ENREGE No. 525/26
October 2026	2.0%	ENREGE No. 691 and 695/26	2.3%	ENREGE No. 711/26
November 2026	2.7%	ENREGE No. 860 and 864/26	2.9%	ENREGE No.842/26

TGS's NGLs Project: approval under RIGI

On October 19, 2026, the approval of the project's admission to the RIGI was publicly announced. The application had been submitted in June 2026. As of the date of this Report, the corresponding resolution is still pending publication.

TGS also entered into additional agreements with natural gas producers, bringing firm contracted capacity to 96% of the project's planned total capacity.

Expected to be completed over the next four years, the project includes the expansion of the Tratayén treatment plant and the construction of a 100-km segregation pipeline, a multi-product pipeline to Bahía Blanca, fractionation and storage facilities, and a marine export terminal. With a total investment estimated at US$3 billion, the NGL project will strengthen Argentina's midstream infrastructure and its capacity to monetize Vaca Muerta's NGLs.

Dividend distribution at Transener

On August 27, 2026, Transener's Shareholders' Meeting approved a cash dividend totaling AR$253 billion, equivalent to AR$570 per share. The dividend was paid on September 10, 2026.

1. Analysis of Q3 26 results

Breakdown by segment In US$ million	Q3 26			Q3 25			Variation		
	Sales	Adjusted EBITDA	Net Income	Sales	Adjusted EBITDA	Net Income	*Sales*	*Adjusted EBITDA*	*Net Income*
Oil and Gas	342	170	24	308	171	(9)	*+11%*	*-1%*	*NA*
Power generation	378	160	90	205	120	6	*+84%*	*+33%*	*NA*
Petrochemicals	151	9	(8)	115	(5)	(2)	*+31%*	*NA*	*+300%*
Holding, transport and others	6	59	23	6	36	28	-	*+63%*	*-18%*
Eliminations	(87)	-	-	(43)	-	-	*+102%*	*NA*	*NA*
Total	**790**	**398**	**129**	**591**	**322**	**23**	***+34%***	***+23%***	***NA***

Note: Net income is attributable to the Company's shareholders.

Reconciliation of adjusted EBITDA, in US$ million	Nine-month period		Third quarter	
	2026	2025	2026	2025
Consolidated operating income	645	402	196	168
Consolidated depreciations and amortizations	405	305	141	124
Reporting EBITDA	**1,050**	**707**	**337**	**292**
Adjustments from oil and gas segment	(27)	(11)	(7)	(7)
Adjustments from generation segment	(25)	29	7	15
Adjustments from petrochemicals segment	25	(17)	21	(0)
Adjustments from holding, transport & others segment	115	70	40	22
Consolidated adjusted EBITDA	**1,137**	**778**	**398**	**322**
At our ownership	***1,133***	***777***	***397***	***322***

2.1 Analysis of the oil and gas segment

Oil & gas segment, consolidated Figures in US$ million	Nine-month period			Third quarter		
	2026	2025	Δ%	2026	2025	Δ%
Sales revenue	923	658	*+40%*	342	308	*+11%*
Domestic sales	*667*	*515*	*+30%*	*296*	*231*	*+28%*
Foreign market sales	*256*	*143*	*+79%*	*46*	*77*	*-41%*
Cost of sales	(628)	(461)	*+36%*	(232)	(191)	*+21%*
Gross profit	**295**	**197**	***+50%***	**110**	**117**	***-6%***
Selling expenses	(75)	(56)	*+34%*	(27)	(22)	*+23%*
Administrative expenses	(65)	(60)	*+8%*	(23)	(20)	*+15%*
Other operating income	31	41	*-24%*	16	25	*-36%*
Other operating expenses	(11)	(16)	*-31%*	(6)	(8)	*-25%*
Recovery of impairment/(Impairment) of financial assets	3	(5)	*NA*	1	(3)	*NA*
Impairment of PPE and inventories	(1)	(8)	*-88%*	-	(7)	*-100%*
Results for participation in joint businesses	8	2	*+300%*	1	-	*NA*
Operating income	**185**	**95**	***+95%***	**72**	**82**	***-12%***
Finance income	1	-	*NA*	1	-	*NA*
Finance costs	(96)	(77)	*+25%*	(39)	(22)	*+77%*
Other financial results	(23)	(25)	*-8%*	(11)	(25)	*-56%*
Financial results, net	***(118)***	***(102)***	***+16%***	***(49)***	***(47)***	***+4%***
Loss before tax	**67**	**(7)**	***NA***	**23**	**35**	***-34%***
Income tax	49	(31)	*NA*	1	(44)	*NA*
Net (loss)/income for the period	**116**	**(38)**	***NA***	**24**	**(9)**	***NA***
Adjusted EBITDA	**455**	**298**	***+53%***	**170**	**171**	***-1%***
Increases in PPE and right-of-use assets	633	720	*-12%*	209	267	*-22%*
Depreciation and amortization	297	214	*+39%*	105	96	*+9%*
Lifting cost	207	162	*+28%*	77	59	*+31%*
Lifting cost per boe	7.4	6.9	*+7%*	8.3	6.4	*+30%*

Sales in the oil and gas segment rose 11% year-on-year in Q3 26, mainly driven by higher gas sales to our thermal power plants, tariff increases in the retail segment, and the ramp-up of shale oil production at Rincon de Aranda. These effects were partially offset by lower realized oil prices due to hedging, lower volumes sold under Plan Gas following the assignment of GSAs to our power generation business, and reduced gas deliveries to industries and exports to Chile. Quarter-on-quarter, sales increased slightly by 2%, reflecting seasonal gas price increases and higher crude oil volumes sold, partially offset by a drop in gas sales to industrial customers and export markets as we prioritized domestic supply for thermal power generation.

Regarding **operational performance**, total production reached 99.7 kboepd in Q3 26, in line with Q3 25. Higher gas demand from our thermal power plants and increased crude oil production at RDA offset lower deliveries to industrial customers and export markets. Compared with Q2 26, production declined 7%, due to lower thermal dispatch amid increased rainfall during winter associated with the 'El Niño' effect. In addition, RDA's production was temporarily affected in July and August by the precautionary shut-in of certain producing wells during drilling and completion activities at nearby pads. Following the reopening of these wells and the tie-in of new wells, RDA's monthly production exceeded 26 kbpd in September. These effects were partially offset by higher seasonal gas demand from the retail segment.

Gas production averaged 13.2 mcmpd (-6% vs. Q3 25, -8% vs. Q2 26). Among our operated blocks, Sierra Chata led production with 6.8 mcmpd in Q3 26 (+29% vs. Q3 25, -6% vs. Q2 26). No new wells tied in since May 2026, although 4 wells were drilled during Q3 26. El Mangrullo contributed 4.5 mcmpd (-35% vs. Q3 25, -13% vs. Q2 26), with no new wells tied in since July 2024. Together, Sierra Chata and El Mangrullo accounted for 86% of total gas production. Associated gas from Rincón de Aranda and the Parva Negra Este exploratory well contributed 0.2 mcmpd (-47% vs. Q2 26).

In non-operated areas, Río Neuquén produced 1.3 mcmpd (in line with Q3 25, +22% vs. Q2 26), driven by the tie-in of 3 new tight gas wells. Production at Rincón del Mangrullo and Aguaragüe continued to decline, reaching a combined 0.2 mcmpd, explained by natural reservoir decline in the absence of new activity.

Oil and gas' key performance indicators	2026			2025			Variation		
	Oil	Gas	Total	Oil	Gas	Total	*Oil*	*Gas*	***Total***
Nine-month period									
Volume									
Production									
In thousand m^3/day	3.4	13,750		1.5	12,911				
In million cubic feet/day		486			456		*+127%*	*+6%*	***+20%***
In thousand boe/day	21.7	80.9	**102.6**	9.6	76.0	**85.5**			
Sales									
In thousand m^3/day	3.4	13,906		1.6	12,932				
In million cubic feet/day		491			457		*+112%*	*+8%*	***+20%***
In thousand boe/day	21.6	81.8	**103.4**	10.1	76.1	**86.3**			
Average Price									
In US$/bbl	57.5			61.9			*-7%*	*+8%*	
In US$/MBTU		4.2			3.9				
Third quarter									
Volume									
Production									
In thousand m^3/day	3.5	13,184		2.7	13,967				
In million cubic feet/day		466			493		*+28%*	*-6%*	***+0%***
In thousand boe/day	22.1	77.6	**99.7**	17.3	82.2	**99.5**			
Sales									
In thousand m^3/day	3.7	13,556		3.2	13,913				
In million cubic feet/day		479			491		*+15%*	*-3%*	***+1%***
In thousand boe/day	23.0	79.8	**102.8**	20.1	81.9	**102.0**			
Average Price									
In US$/bbl	55.7			61.1			*-9%*	*+12%*	
In US$/MBTU		5.0			4.4				

Note: Net production in Argentina. Gas volume standardized at 9,300 kCal. Oil price is net of hedge, export duty and quality/logistic discounts. Nine-month period of 2025 includes production from El Tordillo and La Tapera-Puesto Quiroga, blocks transferred to Crown Point Energía S.A. in October 2025 (crude oil production of 1.5 kbpd during 9M25 and 1.6 kbpd in Q3 25).

The average **gas price** increased 12% vs. Q3 25 to US$5.0 per MBTU, due to higher pass-through of the cost of our own gas consumed in power generation, as CAMMESA allowed it to be linked to LNG prices during the winter, and, to a lesser extent, retail tariff increases that outpaced AR$ depreciation. Lower prices in export and large users markets partially offset these effects. Compared with Q2 26, the realized price increased 8%, mainly due to higher pass-through of gas costs to our thermal power plants.

Regarding the breakdown of **gas sales by customer**, during Q3 26, 17% of sales volume was allocated to CAMMESA for thermal dispatch (34% in Q3 25) and 44% to retail distributors (37% in Q3 25). Together, these segments accounted for 61% of volume sold under Plan Gas, compared with 71% in Q3 25, reflecting the transfer of GSAs to our power generation business. As a result, intersegment consumption increased to 30% of total sales (9% in Q3 25), mainly driven by fuel self-procurement at CTGEBA and CTLL and, to a lesser extent, at CTIW, under the new WEM guidelines and the higher pass-through of fuel costs by CAMMESA. Intersegment consumption also includes recurring but marginal supply to our petrochemical plants. The remaining 9% of volume sold comprised industrial/spot sales (3% vs. 12% in Q3 25) and exports to Chile (6% vs. 8% in Q3 25).

Oil production reached 22.1 kbpd in Q3 26 (+28% vs. Q3 25), driven by the accelerated ramp-up at RDA, which averaged 20.9 kbpd (+6.4 kbpd vs. Q3 25, -6% vs. Q2 26). Compared with Q2 26, the 5% decline in total production was due to the precautionary shut-in of certain producing wells during drilling and completion activities at nearby pads. In August, 10 wells were tied in, bringing the total producing wells at RDA to 53 (vs. 20 in Q3 25 and 43 in Q2 26). Previously shut-in wells were also brought back online, enabling RDA to reach a monthly crude oil production record of over 26 kbpd in September. At quarter-end, 13 drilled wells were pending completion, including 3 drilled during Q3 26. The divestment of El Tordillo and La Tapera-Puesto Quiroga in October 2025 partially offset year-on-year production growth (-1.6 kbpd vs. Q3 25).

The **oil price**, net of hedge, export duty and commercial discounts, averaged US$55.7 per barrel (-9% vs. Q3 25, -5% vs. Q2 26), impacted by the Brent hedge on RDA's production, while the slight sequential decline was due to higher discounts on domestic sales. Excluding the hedge impact, the realized price would have been US$84.0 per barrel, resulting approximately US$60 million in additional revenue. Exports accounted for 52% of total crude oil volume sold in Q3 26 (47% in Q3 25 and 57% in Q2 26).

The **lifting cost**[4] totaled US$77 million in Q3 26, up 31% year-on-year, explained by the commissioning of the second TPF at RDA, which expanded treatment capacity from 20 to 28 kbpd, in addition to scheduled maintenance and higher activity levels at Sierra Chata. These effects were partially offset by lower labor costs following the divestment of El Tordillo and lower gas treatment costs at El Mangrullo associated with reduced production. Compared with Q2 26, lifting costs remained broadly stable (US$75 million in Q2 26).

Lifting cost per boe was US$8.3/boe produced, +30% vs. Q3 25, as costs increased faster than production. Compared with Q2 26, lifting cost per boe rose 9%, mainly reflecting the 7% sequential decline in production.

Excluding depreciation, amortization and lifting costs, **other operating costs** totaled US$106 million (+20% vs. Q3 25, +17% vs. Q2 26), mainly due to higher royalties associated with increased crude oil production and higher gas selling prices, as well as higher transportation and labor costs, partially offset by lower crude oil inventories.

Other operating income, net of expenses decreased by US$7 million vs. Q3 25 to US$10 million, explained by lower income from Plan Gas compensation, net of royalties, as higher realized prices in the retail segment in US$ terms reduced the compensation received. Lower commercial interest income due to improved collections also contributed to the decline. These effects were partially offset by lower environmental remediation and bad debt provisions. Compared with Q2 26, this item remained stable, as higher income from winter Plan Gas compensation was offset by lower provision reversals.

Financial results in Q3 26 recorded a net loss of US$49 million (+4% vs. Q3 25, -9% vs. Q2 26), driven mainly by increased interest expenses due to higher debt outstanding and losses on Brent derivatives not designated as hedging instruments, partially offset by lower FX losses resulting from a slower AR$ devaluation on the net asset position denominated in local currency.

4 It only considers maintenance, treatment, internal transportation, wellhead staff and the TPF rental costs at Rincón de Aranda, which under IFRS it is recorded as Leases, accruing amortization on rights-of-use in the cost of sales. Lifting cost does not include amortizations and depreciations.

Reconciliation of adjusted EBITDA from oil & gas, in US$ million	Nine-month period		Third quarter	
	2026	2025	2026	2025
Consolidated operating income	185	95	72	82
Consolidated depreciations and amortizations	297	214	105	96
Reporting EBITDA	**482**	**309**	**177**	**178**
Deletion of PPE and inventories' impairment	1	8	-	7
Deletion of gain from commercial interests	(5)	(7)	(1)	(5)
Deletion of SESA's equity income	(8)	(2)	(1)	-
Reclassification of TPF lease as lifting cost	(15)	(10)	(5)	(10)
Adjusted EBITDA from oil & gas	**455**	**298**	**170**	**171**

Our oil and gas **adjusted EBITDA** amounted to US$170 million in Q3 26, in line with Q3 25, primarily explained by gas sales to our thermal power plants, supported by vertical integration following the WEM normalization guidelines, and higher gas prices in the retail segment. These effects were partially offset by the impact of the hedge on oil prices, higher treatment costs at RDA and royalties. Compared with Q2 26, adjusted EBITDA decreased 7%, mainly due to lower stock in crude oil inventories and, to a lesser extent, higher transportation, personnel and lifting costs, partially offset by Plan Gas compensation seasonality and higher gas prices to our thermal power plants. The adjusted EBITDA excludes extraordinary and non-cash income and expenses, overdue commercial interests, and equity income from affiliates, and includes a US$5 million reclassification to lifting costs related to the TPF lease at RDA, which is recognized as a lease under IFRS.

Capital expenditures amounted to US$209 million (-22% vs. Q3 25, -8% vs. Q2 26), explained by the recognition of right-of-use assets for TPF 1 at RDA in Q3 25. Compared with Q2 26, the decrease was driven by lower activity at Sierra Chata and Río Neuquén. Out of the US$209 million recorded in Q3 26, 76% was allocated to the development of RDA (-27% vs. Q3 25, -4% vs. Q2 26).

2.2 Analysis of the power generation segment

Power generation segment, consolidated Figures in US$ million	Nine-month period			Third quarter		
	2026	2025	Δ%	2026	2025	Δ%
Sales revenue	1,008	585	*+72%*	378	205	*+84%*
Cost of sales	(661)	(319)	*+107%*	(253)	(114)	*+122%*
Gross profit	**347**	**266**	***+30%***	**125**	**91**	***+37%***
Selling expenses	(4)	(3)	*+33%*	(2)	(1)	*+100%*
Administrative expenses	(34)	(31)	*+10%*	(12)	(10)	*+20%*
Other operating income	10	17	*-41%*	2	4	*-50%*
Other operating expenses	(11)	(9)	*+22%*	(4)	(4)	-
Results for participation in joint businesses	68	5	*NA*	8	(2)	*NA*
Operating income	**376**	**245**	***+53%***	**117**	**78**	***+50%***
Finance income	13	15	*-13%*	5	7	*-29%*
Finance costs	(25)	(36)	*-31%*	(7)	(11)	*-36%*
Other financial results	36	81	*-56%*	7	1	*NA*
Financial results, net	***24***	***60***	***-60%***	***5***	***(3)***	***NA***
Profit before tax	**400**	**305**	***+31%***	**122**	**75**	***+63%***
Income tax	(88)	(180)	*-51%*	(32)	(69)	*-54%*
Net income for the period	**312**	**125**	***+150%***	**90**	**6**	***NA***
Attributable to owners of the Company	*308*	*125*	*+146%*	*90*	*6*	*NA*
Attributable to non-controlling interests	*4*	-	*NA*	-	-	*NA*
Adjusted EBITDA	**459**	**361**	***+27%***	**160**	**120**	***+33%***
Adjusted EBITDA at our share ownership	***455***	***360***	***+26%***	***160***	***120***	***+33%***
Increases in PPE and right-of-use assets	15	46	*-67%*	11	18	*-37%*
Depreciation and amortization	108	87	*+24%*	36	27	*+33%*

In Q3 26, power generation **sales** grew 84% year-on-year, driven mainly by higher revenues from fuel self-procurement for our thermal power units operating under the spot market, including the recognition of LNG consumed at CTGEBA and CTEB during July and August. The fuel recognition is offset by the cost of gas purchased from our oil and gas segment and LNG procured through ENARSA's auctions, both recorded as cost of sales. Additionally, fuel procurement generates a 25% margin over the reference CVP. Sales growth also reflected higher thermal dispatch margins in the spot market, supported by increased system marginal prices, increased B2B PPA sales to large users in the MAT at CTLL and CTGEBA, and the return to service of CTLL's GT04, which had been unavailable during Q3 25. These effects were partially offset by the expiration of Energía Plus contracts and lower dispatch from the PEPE wind farms, which sell their energy under the MATER.

Compared with Q2 26, sales increased 8%, driven by higher availability and dispatch of thermal units in the spot market, greater fuel cost recognition, increased volumes sold under B2B PPAs in the MAT, and the return to service of CTLL's GT04, which had been unavailable until May 2026. These effects were partially offset by the expiration of HINISA's concession in July 2026.

Within the spot segment, capacity payments for CCGTs averaged US$5.8 thousand per MW-month (+9% vs. Q3 25, +28% vs. Q2 26). Moreover, open-cycle units averaged US$7.5 thousand per MW-month (+28% vs. Q3 25, +21% vs. Q2 26), supported by CTGEBA's ability to operate on alternative fuels. Hydros averaged US$2.5 thousand per MW-month (+22% vs. Q3 25, +9% vs. Q2 26).

Regarding **operational performance**, operated power generation decreased by 2% year-on-year, while total generation in the national grid increased by 4%. The decline in operated generation was driven by higher rainfall associated with the El Niño effect, which increased hydropower across the grid, as well as milder temperatures that reduced thermal dispatch at CTEB (-315 GWh), CTGEBA's old CCGT (-91 GWh), and CPB (-41 GWh). The dispatch reduction was also contributed by lower wind resources affecting the output from the PEPE wind farms, and CTEB was out of service for 4 days in August following a failure in

GT02's diesel burners. These effects were partially offset by higher hydropower generation at HPPL and HIDISA (+146 GWh), as well as increased dispatch at CTIW (+64 GWh), CTLL (+50 GWh), and CTPP (+41 GWh), supported by greater gas availability.

The average **availability** of Pampa's operated units reached 94.3% in Q3 26 vs. 94.0% in Q3 25 (+30 basis points), mainly reflecting the scheduled maintenance at CTGEBA's GT04 during Q3 25, partially offset by outages at CTEB. However, thermal availability decreased 169 basis points to 95.4% in Q3 26. In Q2 26, total and thermal availability stood at 88.4% and 91.2%, respectively.

Power generation's key performance indicators	2026				2025				Variation			
	Wind	Hydro	Thermal	**Total**	Wind	Hydro	Thermal	**Total**	*Wind*	*Hydro*	*Thermal*	***Total***
Installed capacity (MW)	427	673	4,107	**5,207**	427	938	4,107	**5,472**	-	*-28%*	-	***-5%***
Contracted capacity (MW)	427	-	1,494	**1,921**	427	-	1,344	**1,771**	-	*na*	*+11%*	***+8%***
Market share (%)	1.0%	1.5%	9.2%	**11.7%**	1.0%	2.1%	9.4%	**12.5%**	*-0%*	*-1%*	*-0%*	***-1%***
Nine-month period												
Net generation (GWh)	1,196	1,035	14,185	**16,416**	1,244	1,027	13,806	**16,077**	*-4%*	*+1%*	*+3%*	***+2%***
Volume sold (GWh)	1,201	1,034	14,283	**16,519**	1,254	1,027	14,376	**16,657**	*-4%*	*+1%*	*-1%*	***-1%***
Average price (US$/MWh)	68	26	84	**79**	70	22	40	**41**	*-2%*	*+15%*	*+111%*	***+94%***
Average gross margin (US$/MWh)	54	13	32	**33**	54	10	24	**26**	*+0%*	*+33%*	*+33%*	***+27%***
Third quarter												
Net generation (GWh)	390	377	4,548	**5,315**	420	249	4,752	**5,421**	*-7%*	*+51%*	*-4%*	***-2%***
Volume sold (GWh)	390	377	4,549	**5,316**	428	249	4,908	**5,585**	*-9%*	*+51%*	*-7%*	***-5%***
Average price (US$/MWh)	68	21	105	**96**	70	27	42	**43**	*-2%*	*-23%*	*+152%*	***+124%***
Average gross margin (US$/MWh)	52	9	36	**35**	54	9	25	**27**	*-4%*	*-5%*	*+43%*	***+32%***

Note: Gross margin before amortization and depreciation. Thermal power generation includes CTEB (co-operated by Pampa, with a 50% equity stake). In hydropower generation, HINISA's concession expired on July 31, 2026

Excluding depreciation and amortization, **operating costs** increased to US$231 million in Q3 26 (+136% year-on-year, +8% vs. Q2 26), mainly due to higher gas purchases from our E&P segment and LNG procurement to fuel our thermal power plants. Compared with Q2 26, fuel acquisition costs increased due to seasonal demand and the impact of LNG procurement costs. Operating expenses, excluding fuel, increased to US$48 million (+23% vs. Q3 25, +16% vs. Q2 26), mainly due to the penalty incurred for returning unused LNG at CTGEBA amid lower-than-expected thermal generation requirements, as well as higher maintenance expenses.

Other net operating income, **net of expenses** posted a US$2 million loss vs. breakeven in Q3 25, explained by lower insurance recoveries and a higher accrual of the tax on bank account credits and debits.

Financial results in Q3 26 recorded a net gain of US$5 million, vs. a net loss of US$3 million in Q3 25, explained by lower FX losses resulting from a smaller AR$ devaluation on the net asset position in that currency, as well as lower interest expenses due to reduced outstanding debt. Quarter-on-quarter, the net gain increased 25%, mainly reflecting lower AR$ depreciation.

Reconciliation of adjusted EBITDA from power generation, in US$ million	Nine-month period		Third quarter	
	2026	2025	2026	2025
Consolidated operating income	376	245	117	78
Consolidated depreciations and amortizations	108	87	36	27
Reporting EBITDA	**484**	**332**	**153**	**105**
Deletion of CTEB's equity income	(68)	(5)	(8)	2
Deletion of commercial interests to CAMMESA	(5)	(4)	(2)	(2)
CTEB's EBITDA, at our 50% ownership	48	38	17	15
Adjusted EBITDA from power generation	**459**	**361**	**160**	**120**

Adjusted EBITDA from the power generation segment reached US$160 million in Q3 26, +33% vs. Q3 25, supported by stronger spot margins from our thermal units operating under the new regulatory framework, particularly the most competitive units at CTGEBA and CTLL, in addition to higher capacity and energy sales under the MAT to industrial customers. These effects were partially offset by the expiration of Energía Plus contracts, higher maintenance costs, and weaker performance of the PEPE wind farms. Compared with Q2 26, adjusted EBITDA increased 3%, mainly driven by higher spot margins resulting from increased system marginal prices and fuel procurement, greater MAT sales from CTGEBA, and the return to service of CTLL's GT04, which became available again at the end of May and has operated under the spot market since mid-July. Higher maintenance costs partially offset said effects. Adjusted EBITDA excludes non-operating, extraordinary and non-cash items and considers CTEB's 50% ownership, which contributed US$17 million in Q3 26 (+10% vs. Q3 25, flat vs. Q2 26).

Capital expenditures, excluding CTEB, totaled US$11 million in Q3 26, vs. US$18 million in Q3 25, mainly allocated to maintenance activities.

2.3 Analysis of the petrochemicals segment

Petrochemicals segment, consolidated Figures in US$ million	Nine-month period			Third quarter		
	2026	2025	Δ%	2026	2025	Δ%
Sales revenue	377	329	*+15%*	151	115	*+31%*
Domestic sales	*205*	*190*	*+8%*	*82*	*59*	*+39%*
Foreign market sales	*172*	*139*	*+24%*	*69*	*56*	*+23%*
Cost of sales	(324)	(319)	*+2%*	(132)	(113)	*+17%*
Gross profit	**53**	**10**	***NA***	**19**	**2**	***NA***
Selling expenses	(9)	(9)	-	(3)	(3)	-
Administrative expenses	(4)	(5)	*-20%*	(1)	(2)	*-50%*
Other operating income	1	19	*-95%*	-	-	*NA*
Other operating expenses	(37)	(8)	*NA*	(27)	(3)	*NA*
Operating income	**4**	**7**	***-43%***	**(12)**	**(6)**	***+100%***
Finance income	-	27	*-100%*	-	-	*NA*
Other financial results	(8)	4	*NA*	(1)	1	*NA*
Financial results, net	***(8)***	***31***	***NA***	***(1)***	***1***	***NA***
Profit before tax	**(4)**	**38**	***NA***	**(13)**	**(5)**	***+160%***
Income tax	2	(11)	*NA*	5	3	*+67%*
Net income for the period	**(2)**	**27**	***NA***	**(8)**	**(2)**	***+300%***
Adjusted EBITDA	**29**	**(6)**	***NA***	**9**	**(5)**	***NA***
Increases in PPE	-	14	*-100%*	-	8	*-100%*
Depreciation and amortization	-	4	*-100%*	-	1	*-100%*

Reconciliation of adjusted EBITDA from petrochemicals, in US$ million	Nine-month period		Third quarter	
	2026	2025	2026	2025
Consolidated operating income	4	7	(12)	(6)
Consolidated depreciations and amortizations	-	4	-	1
Reporting EBITDA	**4**	**11**	**(12)**	**(5)**
Deletion of project-related expenses	4	-	-	-
Deletion of gain from commercial interests	(0)	(0)	(0)	(0)
Deletion of contingencies adjustment	-	(17)	-	-
Deletion of restructuring costs	21	-	21	-
Adjusted EBITDA from petrochemicals	**29**	**(6)**	**9**	**(5)**

The **adjusted EBITDA** for the petrochemicals segment was US$9 million in Q3 26, compared with a US$5 million loss in Q3 25, driven by higher international prices, which supported stronger margins primarily on the Reformer and, to a lesser extent, styrene products. Adjusted EBITDA excludes US$21 million in costs associated with the restructuring of the business. Compared with Q2 26, adjusted EBITDA decreased 57% due to lower international prices, partially offset by higher exports of Reformer products.

Total **volume sold** reached 115 thousand tons vs. 122 thousand tons in Q3 25, -6% year-on-year, due to the closure of the rubber plant. However, the 22% quarter-on-quarter increase was mainly attributable to higher exports of octane bases and naphtha, both Reformer products.

Financial results recorded a net loss of US$1 million, vs. a net profit of US$1 million in Q3 25, due to lower FX gains resulting from a lower AR$ devaluation on the segment's net liability position in that currency.

Petrochemicals' key performance indicators	Products			Total
	Styrene & polystyrene[1]	SBR	Reforming & others	
Nine-month period				
Volume sold 2026 (thousand ton)	**60**	**29**	**205**	**294**
Volume sold 2025 (thousand ton)	62	31	238	331
Variation 2026 vs. 2025	*-2%*	*-6%*	*-14%*	*-11%*
Average price 2026 (US$/ton)	**1,796**	**1,786**	**1,064**	**1,285**
Average price 2025 (US$/ton)	1,514	1,679	770	993
Variation 2026 vs. 2025	*+19%*	*+6%*	*+38%*	*+29%*
Third quarter				
Volume sold Q3 26 (thousand ton)	**20**	**5**	**90**	**115**
Volume sold Q3 25 (thousand ton)	20	11	91	122
Variation Q3 26 vs. Q3 25	*-2%*	*-50%*	*-1%*	*-6%*
Average price Q3 26 (US$/ton)	**1,957**	**1,950**	**1,130**	**1,309**
Average price Q3 25 (US$/ton)	1,496	1,561	741	937
Variation Q3 26 vs. Q3 25	*+31%*	*+25%*	*+52%*	*+40%*

Note: **1** Includes propylene.

2.4 Analysis of the holding, transport and others segment

Holding, transport and others segment, consolidated Figures in US$ million	Nine-month period			Third quarter		
	2026	2025	Δ%	2026	2025	Δ%
Sales revenue	23	18	*+28%*	6	6	-
Gross profit	**23**	**18**	***+28%***	**6**	**6**	**-**
Selling expenses	-	(1)	*-100%*	-	-	*NA*
Administrative expenses	(40)	(35)	*+14%*	(15)	(15)	-
Other operating income	5	8	*-38%*	1	3	*-67%*
Other operating expenses	(24)	(29)	*-17%*	(9)	(7)	*+29%*
Recovery of impairment on intangible assets	-	-	*NA*	1	-	*NA*
Results for participation in joint businesses	116	94	*+23%*	35	27	*+30%*
Operating income	**80**	**55**	***+45%***	**19**	**14**	***+36%***
Finance costs	(20)	(38)	*-47%*	(7)	(19)	*-63%*
Other financial results	17	77	*-78%*	5	38	*-87%*
Financial results, net	***(3)***	***39***	***NA***	***(2)***	***19***	***NA***
Profit before tax	**77**	**94**	***-18%***	**17**	**33**	***-48%***
Income tax	16	8	*+100%*	6	(5)	*NA*
Net income for the period	**93**	**102**	***-9%***	**23**	**28**	***-18%***
Adjusted EBITDA	**195**	**125**	***+56%***	**59**	**36**	***+63%***
Increases in PPE	299	7	*NA*	297	3	*NA*
Depreciation and amortization	-	-	*NA*	-	-	*NA*

Excluding equity income from affiliates, the holding, transport and others segment recorded an **operating margin** loss of US$16 million in Q3 26, 23% higher year-on-year, mainly due to higher accruals for executive compensation and the personal assets tax. Compared with Q2 26, the operating loss remained stable.

Financial results recorded a net loss of US$2 million in Q3 26, vs. net profits of US$19 million in Q3 25 and US$18 million in Q2 26, due to lower FX gains resulting from a lower AR$ devaluation on the segment's net liability position in that currency, partially offset by lower interest expenses on tax liabilities.

Reconciliation of adjusted EBITDA from holding, transport and others, in US$ million	Nine-month period		Third quarter	
	2026	2025	2026	2025
Consolidated operating income	80	55	19	14
Consolidated depreciations and amortizations	-	-	-	-
Reporting EBITDA	**80**	**55**	**19**	**14**
Deletion of equity income	(116)	(94)	(35)	(27)
Deletion of gain from commercial interests	(0)	-	-	-
Deletion of recovery of intang. assets' impairment	-	-	(1)	-
Deletion of arbitration costs in OCP Ecuador S.A.	-	8	-	-
TGS's EBITDA adjusted by ownership	161	115	51	36
Transener's EBITDA adjusted by ownership	69	41	25	14
Adjusted EBITDA from holding and others	**195**	**125**	**59**	**36**

The **adjusted EBITDA** for the segment, which excludes non-operating, non-recurring, and non-cash items and includes EBITDA adjusted for equity ownership in TGS and Transener, reached a profit of US$59 million in Q3 26 (+63% vs. Q3 25, +2% vs. Q2 26).

Capital expenditures amounted to US$297 million in Q3 26 vs. US$3 million in Q3 25, mainly explained by the start of construction of the urea plant, following the final investment decision in July 2026.

At **TGS**, the EBITDA adjusted for our stake was US$51 million in Q3 26, +44% vs. Q3 25, mainly explained by higher international benchmark prices in the natural gas liquids segment, increased ethane production volumes, and lower natural gas costs. These effects were partially offset by lower LPG and natural gasoline sales volumes and a lower ethane price. The regulated segment also increased EBITDA in US$ terms, supported by a 6% tariff increase in Q3 26 (vs. 5% in Q3 25), in line with inflation (6% in both Q3 26 and Q3 25) and above the AR$ devaluation (2% in Q3 26 vs. 15% in Q3 25). Adjusted EBITDA remained flat vs. Q2 26.

At **Transener**, the EBITDA adjusted for our stake reached US$25 million (+83% vs. Q3 25, +14% vs. Q2 26), driven by a 5% tariff adjustment, which was broadly in line with inflation at 6% and outpaced the 2% AR$ devaluation.

2. Cash and financial borrowings

As of September 30, 2026, in US$ million	Cash[1]		Financial debt		Net debt	
	Consolidated in FS	Ownership adjusted	Consolidated in FS	Ownership adjusted	**Consolidated in FS**	**Ownership adjusted**
Power generation	849	837	451	451	**(398)**	**(386)**
Petrochemicals	-	-	-	-	**-**	**-**
Holding and others	-	-	-	-	**-**	**-**
Oil and gas	186	186	2,315	2,315	**2,129**	**2,129**
Total under IFRS/Restricted Group	**1,035**	**1,023**	**2,766**	**2,766**	**1,731**	**1,743**
Affiliates at O/S[2]	454	454	449	449	**(5)**	**(5)**
Total with affiliates	**1,489**	**1,477**	**3,215**	**3,215**	**1,726**	**1,738**

Note: Financial debt includes accrued interest. **1** Includes cash and cash equivalents and financial assets at fair value. **2** Under IFRS, the affiliates CTBSA, Transener and TGS are excluded from Pampa's consolidated figures.

3.1 Debt transactions

As of September 30, 2026, Pampa's financial debt under IFRS totaled US$2.766 billion, 46% higher than year-end 2025. Net debt increased from US$801 million as of December 2025 to US$1.731 billion, reflecting higher capital expenditures for the development of RDA and FEPASA, collateral requirements linked to crude oil price hedging, advance payments for the GPM expansion, and contributions to affiliates such as VMOS, SESA, and SMP, partially offset by operating cash flow and US$44 million in dividends received from Transener. Compared with June 30, 2026, net debt increased 31%.

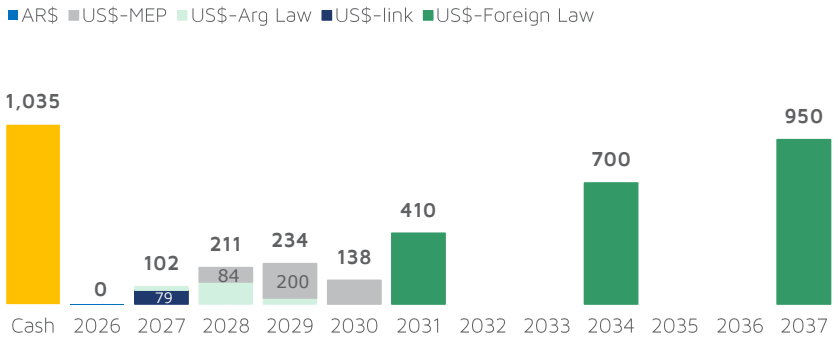
On August 21, 2026, Pampa issued US$138 million of CB Series 28 US$-MEP, maturing in August 2030, with a fixed annual interest rate of 5.50%, payable semiannually.

As of September 30, 2026, 97% of Pampa's gross debt was issued in the capital markets, with the remaining 3% consisting of bank loans. The average cost of financing was 7.2%. Details are shown below:

Type of debt	Currency	Law	Amount in million US$	% over total gross debt	Average rate	Average life
Loans	US$	Argentine	79	3%	5.7%	1.7
CB	US$ MEP	Argentine	422	15%	5.5%	2.9
	US$	Argentine	105	4%	7.3%	1.9
	US$-link	Argentine	79	3%	-	1.2
	US$	Foreign	2,060	75%	7.8%	8.9
Total			**2,745**	**100%**	**7.2%**	**7.3**

Note: Figures in US$ correspond to debt principal and exclude accrued interest. The table excludes bank overdrafts totaling US$0.1 million, repaid after the quarter-end.

The average debt maturity was 7.3 years. The chart below shows the principal maturity profile, net of repurchases, in US$ million as of the end of Q3 26:



Note: The chart considers only Pampa's consolidated IFRS figures and excludes affiliates TGS, Transener, and CTBSA. The cash position includes cash and cash equivalents and financial assets at fair value.

Following quarter-end, FEPASA entered into a loan agreement with Itaú Unibanco S.A., Nassau Branch, for up to US$300 million to finance the development and construction of the urea plant. Said loan has a four-year term, with principal payable at maturity, and bears quarterly interest at a floating rate equal to Term SOFR plus an applicable margin. On October 5, 2026, an initial US$20 million disbursement was made.

Additionally, Pampa issued US$220 million of CB Series 29 US$-MEP, maturing in November 2030, with a fixed annual interest rate of 6.50%, payable semiannually, and also obtained US$28 million in bank financing.

Regarding our affiliates, during Q3 26, CTEB issued US$42 million of CB Series 10 US$-MEP, maturing in January 2028, with a fixed annual interest rate of 4.90%. The first interest payment is due four months after the issuance date and quarterly thereafter. CTEB also repaid US$28 million of net bank debt, made a US$16 million partial prepayment on a bank loan and agreed to extend the maturities of two other bank loans.

TGS secured US$178 million in bank financing and extended the maturity of a US$44 million bank loan bearing an annual interest rate of 4.75%.

In August 2026, the SMP consortium, comprising PAE (30%), YPF (25%), Pampa (20%), Harbour Energy (15%), and Golar LNG (10%), secured a US$900 million syndicated loan under a project finance structure. The proceeds will be destined to fund the construction of the San Matías pipeline, which will connect Tratayén to the Gulf of San Matías, span 472 km, have a transportation capacity of 27 mcmpd, and exclusively supply SESA's two liquefaction vessels. The project was also approved under the RIGI, and construction began in August 2026. Total estimated investment amounts to US$1.3 billion.

Finally, on September 22, 2026, the VMOS consortium, led by YPF and in which Pampa holds a 9% stake, issued the Series 1 limited-recourse Notes for US$234 million, maturing in September 2030, with a fixed annual interest rate of 6.25%. The proceeds are destined to finance the construction of a 437-km oil pipeline with a capacity of 550 kbpd, expandable to 700 kbpd, that will connect Allen with Punta Colorada, together with the complex that includes a storage tank and a deep-water single-point mooring system. Total estimated investment amounts to US$3 billion, and the first stage of commercial operations is expected to begin during the first quarter of 2027.

As of the date of this Report, Pampa remains in full compliance with all covenants under its financing agreements.

3.2 Summary of debt securities

Company In US$ million	Security	Maturity	Amount outstanding	Coupon
In US$ - Foreign Law				
Pampa	CB Series 21	2031	410	7.95%
	CB Series 23	2034	700	7.875%
	CB Series 26	2037	950	7.75%
TGS[1]	CB Series 3	2031	490	8.5%
	CB Series 4	2035	500	7.75%
In US$				
Pampa	CB Series 25	2028	105	7.25%
In US$-link				
Pampa	CB Series 13	2027	79	0%
In US$-MEP				
Pampa	CB Series 22	2028	84	5.75%
	CB Series 27	2029	200	5.49%
	CB Series 28	2030	138	5.5%
	CB Series 29[2]	2030	220	6.5%
CTBSA[1]	CB Series 10	2028	42	4.9%

Note: **1** Under IFRS, affiliates are not consolidated in Pampa's FS. **2** Issued after the quarter's closing, on November 2, 2026.

3.3 Credit ratings

In August 2026, Fitch Ratings upgraded Transener's long-term rating from 'AA' to 'AA+', with a stable outlook.

Company	Agency	Rating	
		Global	Local
Pampa	S&P	B stable, bb- (stand-alone)	na
	FitchRatings	B+	AAA (long-term), A1+ (short-term)[1]
TGS	S&P	B, b+ (stand-alone)	na
	Moody's	B1	na
	FitchRatings	B	na
Transener	FitchRatings	na	AA+ stable (long-term)[1]
CTEB	FitchRatings	na	AAA[1]

Note: **1** Issued by FIX SCR.

3. Appendix

4.1 Analysis of the nine-month period, by subsidiary and segment

Subsidiary In US$ million	Nine-month period 2026				Nine-month period 2025			
	% Pampa	Adjusted EBITDA	Net debt	Net income[2]	% Pampa	Adjusted EBITDA	Net debt	Net income[2]
Oil & gas segment								
Pampa Energía	100.0%	455	2,129	116	100.0%	298	1,311	(38)
Subtotal oil & gas		**455**	**2,129**	**116**		**298**	**1,311**	**(38)**
Power generation segment								
Diamante	61.0%	5	(0)	4	61.0%	6	(0)	3
Los Nihuiles	52.0%	5	(0)	6	52.0%	(2)	(0)	(3)
VAR	100.0%	15	(0)	13	100.0%	12	(0)	3
CTBSA		*95*	*116*	*137*		*76*	*160*	*10*
Non-controlling stake adjustment		*(48)*	*(58)*	*(68)*		*(38)*	*(80)*	*(5)*
Subtotal CTBSA adjusted by ownership	50.0%	48	58	68	50.0%	38	80	5
Pampa stand-alone, other companies, & adj.[1]		386	(398)	216		307	(437)	117
Subtotal power generation		**459**	**(340)**	**308**		**361**	**(357)**	**125**
Petrochemicals segment								
Pampa Energía	100.0%	29	-	(2)	100.0%	(6)	(0)	27
Subtotal petrochemicals		**29**	**-**	**(2)**		**(6)**	**(0)**	**27**
Holding, transport & others segment								
Transener		*264*	*(25)*	*152*		*154*	*(61)*	*92*
Non-controlling stake adjustment		*(194)*	*19*	*(112)*		*(114)*	*45*	*(68)*
Subtotal Transener adjusted by ownership	26.3%	69	(7)	40	26.3%	41	(16)	24
TGS		*600*	*(209)*	*285*		*437*	*(65)*	*199*
Non-controlling stake adjustment		*(438)*	*153*	*(144)*		*(322)*	*47*	*(147)*
Subtotal TGS adjusted by ownership	26.9%	161	(56)	141	26.9%	115	(17)	52
Pampa stand-alone, other companies, & adj.[1]		(36)	-	(88)		(31)	-	25
Subtotal holding & others		**195**	**(63)**	**93**		**125**	**(34)**	**102**
Deletions		-	5	-		-	(46)	-
Total consolidated		**1,137**	**1,731**	**515**		**778**	**874**	**216**
At our share ownership		***1,133***	***1,738***	***515***		***777***	***928***	***216***

Note: **1** The deletion corresponds to other companies or intercompany. **2** Attributable to the Company's shareholders.

4.2 Analysis of the quarter, by subsidiary and segment

Subsidiary In US$ million	Q3 26				Q3 25			
	% Pampa	Adjusted EBITDA	Net debt	Net income[2]	% Pampa	Adjusted EBITDA	Net debt	Net income[2]
Oil & gas segment								
Pampa Energía	100.0%	170	2,129	24	100.0%	171	1,311	(9)
Subtotal oil & gas		**170**	**2,129**	**24**		**171**	**1,311**	**(9)**
Power generation segment								
Diamante	61.0%	1	(0)	1	61.0%	2	(0)	1
Los Nihuiles	52.0%	(0)	(0)	0	52.0%	(1)	(0)	(1)
VAR	100.0%	5	(0)	3	100.0%	4	(0)	(0)
CTBSA		*34*	*116*	*(16)*		*31*	*160*	*(4)*
Non-controlling stake adjustment		*(17)*	*(58)*	*8*		*(15)*	*(80)*	*2*
Subtotal CTBSA adjusted by ownership	50.0%	17	58	(8)	50.0%	15	80	(2)
Pampa stand-alone, other companies, & adj.[1]		137	(398)	94		101	(437)	8
Subtotal power generation		**160**	**(340)**	**90**		**120**	**(357)**	**6**
Petrochemicals segment								
Pampa Energía	100.0%	9	-	(8)	100.0%	(5)	(0)	(2)
Subtotal petrochemicals		**9**	**-**	**(8)**		**(5)**	**(0)**	**(2)**
Holding, transport & others segment								
Transener		*95*	*(25)*	*58*		*52*	*(61)*	*32*
Non-controlling stake adjustment		*(70)*	*19*	*(42)*		*(38)*	*45*	*(23)*
Subtotal Transener adjusted by ownership	26.3%	25	(7)	15	26.3%	14	(16)	8
TGS		*191*	*(209)*	*79*		*132*	*(65)*	*71*
Non-controlling stake adjustment		*(139)*	*153*	*(58)*		*(97)*	*47*	*(52)*
Subtotal TGS adjusted by ownership	26.9%	51	(56)	21	26.9%	36	(17)	19
Pampa stand-alone, other companies, & adj.[1]		(17)	-	(14)		(13)	-	0
Subtotal holding & others		**59**	**(63)**	**23**		**36**	**(34)**	**28**
Deletions		-	5	-		-	(46)	-
Total consolidated		**398**	**1,731**	**129**		**322**	**874**	**23**
At our share ownership		***397***	***1,738***	***129***		***322***	***928***	***23***

Note: **1** The deletion corresponds to other companies or intercompany. **2** Attributable to the Company's shareholders.

4.3 Consolidated balance sheet

In US$ million	As of 09.30.2026	As of 12.31.2025
ASSETS		
Property, plant and equipment	3,863	3,303
Intangible assets	87	89
Right-of-use assets	17	36
Deferred tax asset	234	43
Investments in associates and joint ventures	1,408	1,059
Financial assets at fair value through profit and loss	34	33
Trade and other receivables	85	43
Total non-current assets	**5,728**	**4,606**
Inventories	269	231
Financial assets at fair value through profit and loss	503	366
Derivatives	-	52
Trade and other receivables	1,090	614
Cash and cash equivalents	532	725
Total current assets	**2,394**	**1,988**
Total assets	**8,122**	**6,594**
EQUITY		
Share capital	35	36
Share capital adjustment	189	191
Share premium	517	516
Treasury shares adjustment	1	1
Treasury shares cost	(6)	(54)
Legal reserve	44	44
Voluntary reserve	2,706	2,399
Other reserves	(13)	(12)
Other comprehensive income	39	124
Retained earnings	605	351
Equity attributable to owners of the company	**4,117**	**3,596**
Non-controlling interest	13	9
Total equity	**4,130**	**3,605**
LIABILITIES		
Provisions	76	100
Income tax and minimum notional income tax provision	28	26
Tax liabilities	194	212
Deferred tax liability	47	56
Defined benefit plans	28	26
Borrowings	2,692	1,844
Trade and other payables	68	86
Total non-current liabilities	**3,133**	**2,350**
Provisions	11	13
Income tax liability	156	83
Tax liabilities	100	56
Defined benefit plans	5	6
Salaries and social security payable	44	36
Derivatives	167	-
Borrowings	74	48
Trade and other payables	302	397
Total current liabilities	**859**	**639**
Total liabilities	**3,992**	**2,989**
Total liabilities and equity	**8,122**	**6,594**

4.4 Consolidated income statement

In US$ million	Nine-month period		Third quarter	
	2026	2025	2026	2025
Sales revenue	2,109	1,491	790	591
Domestic sales	*1,681*	*1,207*	*675*	*457*
Foreign market sales	*428*	*284*	115	*134*
Cost of sales	(1,392)	(1,000)	(530)	(375)
Gross profit	**717**	**491**	**260**	**216**
Selling expenses	(88)	(69)	(32)	(26)
Administrative expenses	(142)	(131)	(51)	(47)
Other operating income	47	85	19	32
Other operating expenses	(83)	(62)	(46)	(22)
Recovery of impairment/(Impairment) of financial assets	3	(5)	1	(3)
Recovery of impairment/(Impairment) of PPE, inventories and int. assets	(1)	(8)	1	(7)
Results for part. in joint businesses & associates	192	101	44	25
Operating income	**645**	**402**	**196**	**168**
Financial income	13	42	6	7
Financial costs	(140)	(151)	(53)	(52)
Other financial results	22	137	-	15
Financial results, net	***(105)***	***28***	***(47)***	***(30)***
Profit before tax	**540**	**430**	**149**	**138**
Income tax	(21)	(214)	(20)	(115)
Net income for the period	**519**	**216**	**129**	**23**
Attributable to the owners of the Company	***515***	***216***	***129***	***23***
Attributable to the non-controlling interest	***4***	***-***	***-***	***-***
Net income per share to shareholders	**0.38**	**0.16**	**0.10**	**0.02**
Net income per ADR to shareholders	**9.55**	**3.97**	**2.41**	**0.42**
Average outstanding common shares [1]	***1,348***	***1,360***	***1,340***	***1,360***
Outstanding shares by the end of period [1]	***1,340***	***1,360***	***1,340***	***1,360***

Note: 1 Treats shares allocated to the employee compensation plan as treasury shares, which amounted to 3.9 million and 3.5 million shares as of September 30, 2025 and 2026, respectively. Repurchased shares are deducted from shares outstanding only when held in the form of common shares.

4.5 Consolidated cash flow statement

In US$ million	Nine-month period		Third quarter	
	2026	2025	2026	2025
OPERATING ACTIVITIES				
Profit of the period	519	216	129	23
Adjustments to reconcile net profit to cash flows from operating activities	382	407	187	244
Changes in operating assets and liabilities	(767)	(133)	(163)	76
(Increase) Decrease in trade receivables and other receivables	*(546)*	*(219)*	*(102)*	*35*
(Increase) Decrease in inventories	*(39)*	*(34)*	*14*	*(14)*
Increase in trade and other payables	*17*	*94*	*-*	*29*
Increase in salaries and social security payables	*1*	*2*	*11*	*12*
Defined benefit plan payments	*(2)*	*(2)*	*-*	*(1)*
Increase in tax liabilities	*56*	*25*	*18*	*12*
Decrease in provisions	*(40)*	*(7)*	*(37)*	*(3)*
Income tax payment	*(59)*	*-*	*(9)*	*-*
(Payments) Collection of derivatives, net	*(155)*	*8*	*(58)*	*6*
Net cash generated by operating activities	**134**	**490**	**153**	**343**
INVESTING ACTIVITIES				
Payment of PPE	(1,043)	(751)	(525)	(307)
Collection for sales (Payment for purchases) of debt securities and shares, net	89	376	(116)	60
(Subscription) Recovery of mutual funds, net	(100)	11	(91)	15
Equity contributions to companies	(56)	(41)	(26)	-
Collection for equity interests in companies sales	-	1	-	1
Collection for intangible assets sales	-	9	-	6
Dividends received	46	25	45	25
Proceeds from the sale of interests in blocks	9	2	4	-
Net cash used in investing activities	**(1,055)**	**(368)**	**(709)**	**(200)**
FINANCING ACTIVITIES				
Proceeds from borrowings	869	554	137	174
Payment of borrowings	(32)	(128)	-	(20)
Interest paid on borrowings	(90)	(122)	(22)	(21)
Repurchase and redemption of corporate bonds	(2)	(726)	-	(1)
Purchase of treasury shares	-	(16)	-	(16)
Lease payments	(17)	(11)	(6)	(9)
Net cash generated by (used in) financing activities	**728**	**(449)**	**109**	**107**
Increase (decrease) in cash and cash equivalents	**(193)**	**(327)**	**(447)**	**250**
Cash and cash equivalents at the beginning of the period	725	738	979	161
(Decrease) Increase in cash and cash equivalents	(193)	(327)	(447)	250
Cash and cash equivalents at the end of the period	**532**	**411**	**532**	**411**

4.6 Key operating indicators of the power generation segment, by plant

Power generation's key performance indicators	Wind					Hydroelectric			Subtotal hydro +wind	Thermal										Total
	PEPE2	PEPE3	PEPE4	PEA	PEPE6	HINISA[1]	HIDISA[1]	HPPL		CTLL	CTG	CTP	CPB	CTPP	CTIW	CTGEBA	Eco-Energía	CTEB[2]	Subtotal thermal	
Installed capacity (MW)	53	53	81	100	140	-	388	285	**1,100**	780	361	30	620	100	100	1,254	14	848	**4,107**	**5,207**
Contracted capacity (MW)	*53*	*53*	*81*	*100*	*140*	-	-	-	***427***	*597*	-	-	-	*100*	*100*	*418*	-	*279*	***1,494***	***1,921***
Market share	0.1%	0.1%	0.2%	0.2%	0.3%	na	0.9%	0.6%	**2.5%**	1.7%	0.8%	0.1%	1.4%	0.2%	0.2%	2.8%	0.03%	1.9%	**9.2%**	**11.7%**
Nine-month period																				
Net generation 2026 (GWh)	**141**	**164**	**240**	**254**	**397**	**114**	**337**	**584**	**2,232**	**3,686**	**121**	**40**	**424**	**186**	**248**	**6,248**	**51**	**3,181**	**14,185**	**16,416**
Market share	**0.1%**	**0.2%**	**0.2%**	**0.2%**	**0.4%**	**0.1%**	**0.3%**	**0.5%**	**2.1%**	**3.4%**	**0.1%**	**0.0%**	**0.4%**	**0.2%**	**0.2%**	**5.8%**	**0.0%**	**2.9%**	**13.1%**	**15.1%**
Sales 2026 (GWh)	**146**	**164**	**240**	**254**	**397**	**113**	**337**	**584**	**2,235**	**3,745**	**129**	**42**	**415**	**186**	**248**	**6,274**	**55**	**3,190**	**14,283**	**16,519**
Net generation 2025 (GWh)	149	178	267	226	424	195	366	466	**2,270**	3,248	207	31	439	114	100	6,500	39	3,130	**13,806**	**16,077**
Variation 2026 vs. 2025	*-5%*	*-8%*	*-10%*	*+12%*	*-6%*	*-41%*	*-8%*	*+25%*	***-2%***	*+13%*	*-41%*	*+29%*	*-3%*	*+64%*	*+148%*	*-4%*	*+32%*	*+2%*	***+3%***	***+2%***
Sales 2025 (GWh)	159	178	267	226	424	195	366	466	**2,281**	3,238	379	31	439	114	100	6,850	91	3,136	**14,376**	**16,657**
Avg. price 2026 (US$/MWh)	**74**	**63**	**63**	**81**	**63**	**60**	**32**	**15**	**48**	**63**	**na**	**106**	**na**	**146**	**110**	**80**	**52**	**97**	**84**	**79**
Avg. price 2025 (US$/MWh)	93	63	63	79	63	18	30	18	**48**	30	83	66	76	na	na	37	40	33	**40**	**41**
Avg. gross margin 2026 (US$/MWh)	**47**	**53**	**53**	**61**	**53**	**33**	**18**	**6**	**35**	**29**	**85**	**24**	**63**	**119**	**66**	**29**	**16**	**29**	**32**	**33**
Avg. gross margin 2025 (US$/MWh)	50	54	54	54	55	(2)	19	7	**34**	18	38	30	41	na	na	20	14	26	**24**	**26**
Third quarter																				
Net generation Q3 26 (GWh)	**47**	**54**	**79**	**80**	**130**	**13**	**113**	**252**	**767**	**1,339**	**26**	**7**	**-**	**66**	**84**	**2,010**	**19**	**997**	**4,548**	**5,315**
Market share	**0.1%**	**0.2%**	**0.2%**	**0.2%**	**0.4%**	**0.0%**	**0.3%**	**0.7%**	**2.2%**	**3.8%**	**0.1%**	**0.0%**	**-**	**0.2%**	**0.2%**	**5.7%**	**0.1%**	**2.8%**	**12.8%**	**14.9%**
Sales Q3 26 (GWh)	**47**	**54**	**79**	**80**	**130**	**13**	**113**	**252**	**767**	**1,339**	**26**	**7**	**-**	**66**	**84**	**2,011**	**19**	**997**	**4,549**	**5,316**
Net generation Q3 25 (GWh)	52	62	90	71	145	31	94	124	**669**	1,288	18	6	41	25	19	2,024	18	1,312	**4,752**	**5,421**
Variation Q3 26 vs. Q3 25	*-9%*	*-13%*	*-12%*	*+12%*	*-10%*	*-58%*	*+20%*	*+102%*	***+15%***	*+4%*	*+49%*	*+12%*	*-100%*	*na*	*na*	*-1%*	*+4%*	*-24%*	***-4%***	***-2%***
Sales Q3 25 (GWh)	60	62	90	71	145	31	94	124	**677**	1,278	72	6	41	25	19	2,118	36	1,312	**4,908**	**5,585**
Avg. price Q3 26 (US$/MWh)	**78**	**63**	**63**	**82**	**63**	**64**	**31**	**14**	**45**	**72**	**na**	**146**	**na**	**139**	**127**	**98**	**48**	**139**	**105**	**96**
Avg. price Q3 25 (US$/MWh)	95	62	62	79	62	25	36	20	**54**	35	na	106	na	na	na	39	41	29	**42**	**43**
Avg. gross margin Q3 26 (US$/MWh	**48**	**47**	**47**	**59**	**53**	**21**	**15**	**6**	**31**	**33**	**137**	**22**	**na**	**111**	**64**	**32**	**11**	**29**	**36**	**35**
Avg. gross margin Q3 25 (US$/MWh)	51	52	52	60	53	(13)	22	5	**37**	18	63	47	127	na	na	21	19	24	**25**	**27**

Note: Gross margin before amortization and depreciation. **1** HINISA's concession expired on July 31, 2026. **2** Co-operated by Pampa (50% equity stake).

4.7 Oil and gas production by block

In kboe/day at ownership	Nine-month period			Third quarter		
	2026	2025	*Variation*	2026	2025	*Variation*
Gas						
El Mangrullo	31.0	41.2	*-25%*	26.6	41.2	*-35%*
Sierra Chata	39.7	24.8	*+60%*	40.2	31.0	*+29%*
Río Neuquén	7.1	8.1	*-11%*	7.9	7.9	*+0%*
Rincón del Mangrullo[1]	0.8	1.0	*-16%*	0.8	0.9	*-5%*
Others	2.2	1.0	*+117%*	2.0	1.2	*+74%*
Total gas at working interest	**80.9**	**76.0**	***+6%***	**77.6**	**82.2**	***-6%***
Oil						
Rincón de Aranda	20.5	6.9	*na*	20.9	14.4	*na*
El Tordillo[2]	-	1.5	*-100%*	-	1.6	*-100%*
Associated oil[3]	1.2	1.1	*+8%*	1.2	1.2	*-0%*
Los Blancos	0.0	0.1	*-27%*	0.0	0.1	*-26%*
Total oil at working interest	**21.7**	**9.6**	***+127%***	**22.1**	**17.3**	***+28%***
Total	**102.6**	**85.5**	***+20%***	**99.7**	**99.5**	***+0%***

Note: Production in Argentina. **1** Excludes production from shale formations. **2** Pampa transferred the 35.67% stake in the concession to Crown Point Energía in October 2025, including the La Tapera–Puesto Quiroga block. **3** From gas blocks.

4. Glossary

9M26/9M25: Nine-month period of 2026/ Nine-month period of 2025

ADR/ADS: American Depositary Receipt

AR$: Argentine pesos

B2B: Business-to-business

boe: Barrels of oil equivalent

CAMMESA: Wholesale Electricity Market Clearing Company (Compañía Administradora del Mercado Mayorista Eléctrico S.A.)

CB: Corporate bond

CCGT: Combined cycle

CPB: Piedra Buena Thermal Power Plant

CTBSA: CT Barragán S.A.

CTEB: Ensenada Barragán Thermal Power Plant

CTG: Güemes Thermal Power Plant

CTGEBA: Genelba Thermal Power Plant

CTIW: Ingeniero White Thermal Power Plant

CTLL: Loma De La Lata Thermal Power Plant

CTP: Piquirenda Thermal Power Plant

CTPP: Parque Pilar Thermal Power Plant

CVP: Variable production cost

E&P: Exploration and Production

EBITDA: Earnings before interest, tax, depreciation and amortization

EcoEnergía: EcoEnergía Cogeneration Power Plant

ENARSA: Energía Argentina S.A.

ENREGE: National Gas and Electricity Regulatory Entity (Ente Nacional Regulador del Gas y la Electricidad)

FEPASA: Fértil Pampa S.A.U.

FRA: Adapted Revenue Factor (*Factor de Renta Adaptado*)

FS: Financial Statements

FX: Nominal exchange rate

GPM: 'Perito' Moreno Gas Pipeline

GSA: Gas sale agreement

GT: Gas turbine

GUDI: Large users at distribution network (Gran Usuario de Distribuidora)

GWh: Gigawatt-hour

HIDISA: Diamante Hydro Power Plant

HINISA: Los Nihuiles Hydro Power Plant

HPPL: Pichi Picun Leufu Hydro Power Plant

IFRS: International Financial Reporting Standards

kb/kboe: Thousands of barrels/ thousand barrels of oil equivalent

kbpd/kboepd: Thousands of barrels per day/ thousand barrels of oil equivalent per day

kCal: Kilocalorie

LNG: Liquefied natural gas

LPG: Liquefied petroleum gas

m^3: Cubic meter

MAT/MATE: B2B market/B2B energy market

MATER: Term market from renewable energy

MBTU: million British Thermal Units

mcm/mcmpd: Million cubic meters/ million cubic meters per day

MECON: Ministry of Economy

MEGSA: Mercado Electrónico del Gas S.A.

MW/MWh: Megawatt/Megawatt-hour

n.a.: Not applicable

NGL: Natural gas liquids

Pampa/The Company: Pampa Energía S.A.

PAE: Pan American Energy S.A.

PEA: Arauco II Wind Farm, stages 1 and 2

PEELP: Long-Term Strategic Export Project under RIGI

PEN: National Executive Branch (Poder Ejecutivo Nacional)

PEPE: Pampa Energía Wind Farm

Plan Gas: Argentine Natural Gas Production Promotion Plan (Executive Order No. 892/20, 730/22 and supplementary provisions)

PPA: Power purchase agreement

PPE: Property, plant and equipment

Q2 26: Second quarter of 2026

Q3 26/Q3 25: Third quarter of 2026/ Third quarter of 2025

RDA: Rincón de Aranda

Res.: Resolution/Resolutions

Restricted Group: Pampa Energía S.A., excluding subsidiaries and affiliates

RIGI: Incentive Regime for Large Investments (Régimen de Incentivo para Grandes Inversiones)

SE: Secretariat of Energy

SESA: Southern Energy S.A.

SMP: San Matías Pipeline S.A.

SOFR: Secured Overnight Financing Rate

TGN: Transportadora de Gas del Norte S.A

TGS: Transportadora de Gas del Sur S.A.

Ton: Metric ton

TPF: Temporary processing facility

Transba: Empresa de Transporte de Energía Eléctrica por Distribución Troncal de la Provincia de Buenos Aires Transba S.A.

Transener: Compañía de Transporte de Energía Eléctrica en Alta Tensión Transener S.A.

US$: U.S. Dollar

US$-link: A security linked to wholesale US$ FX

US$-MEP: A security settled with onshore US$

VAR: Vientos de Arauco Renovables S.A.U.

VMOS: Vaca Muerta Oil Sur S.A.

WEM: Wholesale electricity market

YPF: YPF S.A.